Ely Energy Center
SIERRA PACIFIC RESOURCES

APPLICATION FOR OPERATING PERMIT TO CONSTRUCT

VOLUME I

Prepared for:

SIERRA PACIFIC RESOURCES
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Submitted to:

STATE OF NEVADA
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ACRONYMS AND ABBREVIATIONS

Δb_{ext}	Change in light extinction
$\mu g/m^3$	Microgram per cubic meter
µm	Micrometer, also called Micron
AAQS	Ambient Air Quality Standard
AEGI	Amine-enhanced gas injection
AGR	Advanced gas reburning
AQIA	Air quality impact analysis
AQRV	Air quality-related value
BACT	Best available control technology
BPIPPRM	Building Profile Input Program PRIME
CAIR	Clean Air Interstate Rule
CAM	Compliance assurance monitoring
CAMR	Clean Air Mercury Rule
CC	Combustion controls
CDS	Circulating dry scrubber
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CIIC	Compression ignition internal combustion
CO	Carbon monoxide
CO_2	Carbon dioxide
CTG	Composite Theme Grid
CUE	Coal Utility Environmental
DEM	Digital elevation model
DSI	Dry sorbent injection
EC	Elemental carbon
ECO	Electro-Catalytic Oxidation™ (ECO)
EEC	Ely Energy Center
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
ETO	External thermal oxidation
FF	Fabric filter
FGD	Flue gas desulfurization
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FLGR	Fuel lean gas reburning
FLM	Federal land manager
FSI	Furnace sorbent injection
g/hp-hr	Gram per horsepower hour

ACRONYMS AND ABBREVIATIONS (Continued)

g/kW-hr	Gram per kilowatt hour
g/s	Gram per second
gal/hr	Gallon per hour
gal/hp-hr	Gallon per horsepower-hour
GEP	Good engineering practice
GOP	Good operating practice
gr/dscf	Grain per dry standard cubic foot
GWh	Gigawatt-hour
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
HF	Hydrogen fluoride
HNO_3	Nitric acid
hp	Horsepower
hr/yr	Hour per year
IGCC	Integrated gasification combined cycle
IWAQM	Interagency Workgroup on Air Quality Modeling
kg/hectare/yr	Kilogram per hectare per year
km	Kilometer
kW	Kilowatt
lb/hr	Pound per hour
lb/mmBtu	Pound per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/yr	Pound per year
LIDS	Limestone injection dry scrubbing
LNB	Low NO_X burner
LSD	Lime spray dryer absorber
LSFO	Limestone forced oxidation
MACT	Maximum achievable control technology
MM5	National Center for Atmospheric Research/Penn State Mesoscale Model
mmBtu	Million British thermal units
mph	Mile per hour
MW	Megawatt
MWh	Megawatt-hour
N_2	Nitrogen
NA	Not applicable
NAC	Nevada Administrative Code
NAD	North American Datum

ACRONYMS AND ABBREVIATIONS (Continued)

NCDC	National Climatic Data Center
NDEP	Nevada Division of Environmental Protection
NESHAP	National Emission Standard for Hazardous Air Pollutants
ng/J	Nanogram per joule
NGR	Natural gas reburning
NMHC	Non-methane hydrocarbon
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NP	National Park
NPS	National Park Service
NSPS	New Source Performance Standards
NSR Manual	"New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting"
NSR	New Source Review
NWR	National Wildlife Refuge
NWS	National Weather Service
O&M	Operation and maintenance
O_2	Oxygen
O_3	Ozone
OFA	Over fire air
P	Phosphorous
PC	Pulverized coal-fired
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
PMC	Coarse particulate matter
PMF	Fine particulate matter
ppb	Part per billion
ppm	Part per million
ppmv	Part per million by volume
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RATA	Relative accuracy testing audit
RBLC	RACT/BACT/LAER Clearinghouse
RCRA	Resource Conservation and Recovery Act
ROFA®	Rotating opposed fire air
scfm	Standard cubic feet per minute
SCR	Selective catalytic reduction
SIC	Standard Industrial Classification
SIL	Significant impact level

ACRONYMS AND ABBREVIATIONS (Continued)

SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SO_4	Sulfate
SOA	Secondary organic aerosol
SPR	Sierra Pacific Resources
TBD	To be determined
TBP	To be provided
TCEQ	Texas Commission on Environmental Quality
TDS	Total dissolved solids
ton/hr	Ton per hour
ton/yr	Ton per year
UDAQ	Utah Division of Air Quality
UDEQ	Utah Department of Environmental Quality
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile organic compound
WA	Wilderness Area
WDEQ	Wyoming Department of Environmental Quality
WESP	Wet electrostatic precipitator

1.0 INTRODUCTION

Sierra Pacific Resources (SPR) is proposing to build a new power generation plant, the Ely Energy Center (EEC), in White Pine County near Ely, Nevada. Sierra Pacific Power Company and Nevada Power Company will own and jointly operate the EEC. The EEC is a vital part of SPR's integrated resource plan for supplying electric power to meet Nevada's growing electrical demand. The proposed EEC will consist of a two-unit, pulverized coal-fired (PC) plant. The EEC will use a supercritical cycle and will be designed to fire western sub-bituminous coal. Each unit will be rated at 750 megawatts (MW) nominal generating capacity. Ancillary plant equipment will include fuel and waste preparation and handling equipment; fuel and waste loading and unloading, transfer, and storage facilities; a distillate oil-fired auxiliary boiler; fire protection equipment; and auxiliary power facilities. All control equipment has been selected from a best available control technology (BACT) analysis. The EEC will be equipped with a continuous emissions monitoring system (CEMS) that will monitor and record pollutants as required under federal and state regulations.

The proposed EEC will include sources that have the potential to emit regulated air pollutants at concentrations that could exceed the threshold levels; therefore, these sources are classified as major stationary sources. As such, these sources require a Prevention of Significant Deterioration (PSD) evaluation, which is included as parts of this permit application.

This permit application addresses the following specific sources to be permitted, which constitute the primary equipment addressed in this permit application:

1. Two 750-MW PC boilers (nominal)
2. A coal delivery system
3. A coal unloading system
4. A dead coal storage system
5. A live coal storage, crushing, and conveying system
6. A coal reclamation system
7. Coal bunkers for storage of coal prior to firing
8. Lime and soda ash storage silos
9. Fly ash storage silos
10. A fly ash loading system
11. Bottom ash storage silos

12. Multi-cell mechanical draft cooling towers
13. Distillate oil storage tank for locomotive refueling
14. Distillate oil storage tank for boiler ignition fuel, auxiliary boiler fuel, diesel engine generator, and diesel fire water pump fuel
15. Ammonia storage tank system
16. Powdered activated carbon storage silo
17. Gypsum stockout pile
18. Magnesium hydroxide silo
19. Limestone storage pile
20. Various engine driven auxiliary pumps and generators

This application addresses the permitting requirements of the *Nevada Administrative Code* (NAC) Chapter 445B. The information needed for filing a complete application is included in the following sections of the permit application.

Applicant Information

The individuals listed below are familiar with the design of the proposed EEC, the preparation of this permit application, and the requirements of the permitting process.

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Project Location

The proposed EEC site is in White Pine County near Ely, Nevada (see Figure 1-1). The EEC will be located in Sections 16, 17, 20 and 21 of Township 19 North, Range 64 East – Hydrographic Basin 179.

Surrounding Property

The region surrounding the proposed EEC is rural. Surrounding land uses include ranching, agriculture, and recreation. Ely, Nevada is located about 30 miles south of the proposed EEC and has a population of approximately 7,000, with both residential and commercial development, ranching, and recreational use (see Figure 1-2).

Facility Classification

The EEC is an electric power generating facility.

Standard Industrial Classification

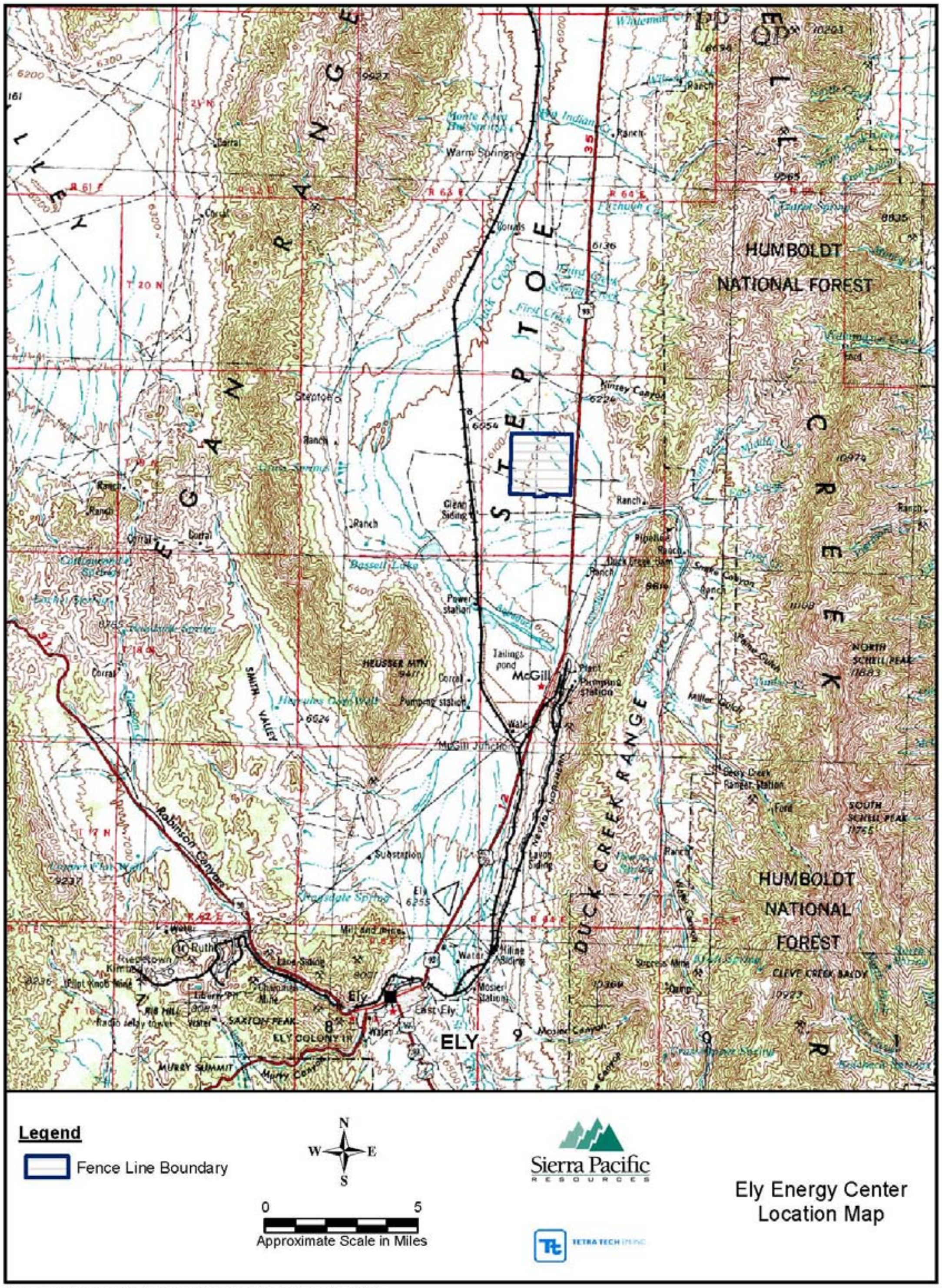
The Standard Industrial Classification (SIC) Code for the EEC is 4911. The EEC is classified as "Electric, Gas, and Sanitary Services" under the major group code and as "electrical generation" under the production activity code. The EEC will be classified under "221112, Fossil Fuel Electric Power Generation" for the transition from the SIC Code to the North American Industry Classification System.

Air Quality Source Designation

Industrial sources are characterized by their potential to emit certain air contaminants referred to as "criteria pollutants." Criteria pollutants include nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), fine particulate matter (particulate matter with an aerodynamic diameter less than 10 microns [PM_{10}]), ozone (volatile organic compounds [VOC] are the precursor to the formation of ozone), and lead. If the potential to emit these pollutants exceeds a pollutant specific threshold quantity, the source is referred to as a "major" source. The EEC is classified as a major source.

FIGURE 1-1
MAP OF SITE AREA

FIGURE 1-2
TOPOGRAPHIC MAP OF SITE



2006-09-30 S:\Project\sppco\steptoe\GIS\Location_Map1-1.mxd Bob Farnes

The ambient air quality in an area is characterized by reference to the National Ambient Air Quality Standards (AAQS) and the Nevada AAQS. The area is referred to as an "attainment" area if levels of specific pollutants are below the levels listed in the National AAQS. The area is referred to as a "non-attainment" area if pollutant levels exceed the National AAQS. The EEC is in an attainment area for all criteria pollutants. The Air Quality Control Region in Nevada has been defined historically by hydrographic basins for determining the attainment status for criteria air pollutants and protection of PSD increments.

Past Permitted Activities

The EEC will be a new facility located at a previously undeveloped site. This undeveloped site, with no prior permit required activities, is referred to as a "Greenfield" site.

1.1 Application Organization

The application text is organized into the following eight sections:

- Section 1.0, Introduction
- Section 2.0, Process Description
- Section 3.0, Emission Estimate References and Documentation
- Section 4.0, Applicable Requirements
- Section 5.0, Best Available Control Technology Analysis
- Section 6.0, Air Quality Impact Analysis
- Section 7.0, Summary
- Section 8.0, References

1.2 SUPPORTING DOCUMENTATION

The Nevada Division of Environmental Protection (NDEP) standard Class I Operating Permit to Construct application packet is included in Appendix A. Appendix B includes the BACT analysis. Attachment A includes reference materials, and Attachment B contains a permit template.

2.0 PROCESS DESCRIPTION

This section discusses the EEC power generation units and balance of plant emission sources. Figure 2-1 at the end of this section presents a schematic diagram of the PC plant power production process, and Figure 2-2 shows the EEC plant layout.

2.1 ELY ENERGY CENTER POWER GENERATION UNITS

The following sections discuss the design, startup, operation, emissions monitoring, and controls for the EEC power generation units, which include PC Boilers 1 and 2.

2.1.1 Boiler Design

PC Boilers 1 and 2 will be PC supercritical dry-bottom boilers. The units will use fuel oil for ignition during startup, shutdown, and flame stabilization when coal pulverizers are placed in and out of service. The igniters will combust low-sulfur distillate fuel oil that contains less than or equal to 0.0015 percent sulfur. Flame stabilization will occur when a pulverizer is placed into service and when it is removed from service. Exhaust gases will exit to the atmosphere through a single concrete stack with an individual flue for each unit.

2.1.2 Boiler Startup

Boiler startup will begin with the introduction and combustion of low-sulfur No. 2 distillate fuel oil that has a sulfur content of less than or equal to 0.0015 percent. Procedures for minimizing emissions during startup are based on the manufacturer's design. Emissions from startup on fuel oil will be reduced through use of atomizers designed to combust the fuel uniformly. Igniters are not intended as a heat source for sustained combustion. Instead, igniters will be used during startup to gradually warm the boiler and during shutdown to gradually cool the boiler to reduce stress on boiler components during startup. Oil igniters will also be used to stabilize the flame when coal pulverizers are placed into service and when they are removed from service. All control systems will be in operation when coal is introduced.

2.1.3 Boiler Operation

Each boiler is designed to operate efficiently at maximum capacity in a continuous duty cycle up to 8,760 hours per year (hr/yr). The supporting documentation is therefore based on this capacity. Each unit will operate by combusting pulverized coal, and the units are not designed — nor is it economically feasible — to operate the units on No. 2 fuel oil. During operation, No. 2 fuel oil may be introduced through the igniters to stabilize the flame. As the load increases or decreases, the pulverizers will introduce raw pulverized coal into the boiler, which can result in unstable or dangerous combustion conditions. Unstable combustion conditions can result in higher emissions if igniters are not introduced to stabilize combustion as the pulverizers are put in service. Additionally, unstable conditions could cause uncombusted coal to ignite violently without the igniters, causing an explosion within the boiler and creating unsafe conditions for workers at the EEC and in the surrounding area.

2.1.4 Emissions Monitoring

The boiler stack will employ CEMS equipment in each flue to track air pollutants in virtually real time. The air pollutants tracked will include SO_2, NO_X, carbon dioxide (CO_2), a diluent, CO, mercury, fuel, and flue gas flow and heat input to the boiler. Opacity monitors will be located in the baghouse outlet ducts to avoid optical interference from wet stack conditions. A CEMS to track SO_2 and the diluent will also be installed at the flue gas desulfurization (FGD) inlet. A data acquisition system will compile, process, and store data for the parameters identified above for the averaging periods specified in the operating permit to construct. The CEMS data will be processed in accordance with Title 40 of the *Code of Federal Regulations* (CFR) Parts 60 and 75 to verify compliance with applicable standards, monitor the operational performance of control equipment, and track SO_2 allowances.

The supplier will provide laboratory analytical results for fuel sulfur content with each delivery to verify that only distillate fuel oil with a sulfur content of 0.0015 percent or less is burned during startup or flame stabilization.

A compliance assurance monitoring (CAM) plan will be developed and submitted to the NDEP Bureau of Air Pollution Control before commercial operation of the EEC begins to verify that the control equipment subject to CAM requirements is operating within specified limits. The CAM plan will specify monitoring procedures that must be followed to ensure that all the control equipment is operating within design parameters.

After the initial CEMS certification, annual relative accuracy testing audits (RATA) will be conducted in accordance with 40 CFR Parts 60 and 75 to verify that the CEMS are meeting the precision and accuracy requirements.

2.1.5 Controls

The PC Boilers 1 and 2 control systems will include coal blending capability; multistage combustion to control CO, VOCs, and NO_X; selective catalytic reduction (SCR) to control NO_X;

a fabric filter system to control particulates and non-volatile metals; and a wet FGD to control SO_2 and semivolatile metals. The FGD and a fabric filter system will control acid gases.

2.2 ELY ENERGY CENTER BALANCE OF PLANT EMISSION SOURCES

This section discusses the design, operation, and control of the EEC's primary fuel handling system, ash handling system, cooling system, auxiliary boiler system, and ancillary equipment.

2.2.1 Primary Fuel Handling System

Primary Fuel Handling System Design

The EEC will use coal as fuel. The coal will be delivered by rail in rotary dump cars to an unloading shed, where the coal will be transferred for storage or use. Dust generated during this activity will be controlled by a fabric filter dust collection system that will remove particulates inside the shed. Conveyors will transfer the coal from the unloading shed to a transfer tower. From this point, coal will be transferred to a storage pile by a retractable chute, transported to dead storage, or transported to the two coal domes. Coal can be loaded directly onto the conveyor belt within each dome and transported to the boiler units. Coal unloaded to the storage pile will be leveled and compacted for later use. Coal in the dome storage or dead coal pile can be reclaimed through a reclaim hopper located directly under these piles and conveyed to the boiler silos through a crusher on covered conveyors. Vibrating feeders located under the reclaim hopper will load fuel onto a conveyor. Dust generated from this operation as well as from all the transfer points and storage bins will be controlled by covered conveyors and a fabric filter dust collection system.

Primary Fuel Handling System Operation

This system is designed for batch operation and may operate any time of the day and during any day of the year (depending on fuel delivery and the unit operating schedule).

Primary Fuel Handling System Controls

Control systems for fuel handling will include a hood system with covered conveyors and fabric filter dust collectors. Hoods and fabric filter dust collectors will be located at each transfer point to control any particulate emissions during transport of the fuel.

2.2.2 Ash Handling System

Ash Handling System Design

Two separate ash-handling systems are associated with each unit to remove bottom ash and fly ash produced from coal combustion. The bottom ash system is a dry system that will convey ash from the hoppers to ash storage silos by a closed conveyor. Ash from the economizer and air heater hoppers will be combined with the bottom ash. Solids will then be removed from the bottom ash silos and transported to an on-site landfill.

The fly ash system is a dry system that will originate at the hoppers below the fabric filter dust collectors. Fly ash will be conveyed to an ash storage silo by a closed pneumatic system. Fly ash will be removed from the fly ash silos for off-site sales or transported to an on-site landfill for disposal.

Ash Handling System Operation

Both units will operate efficiently at maximum capacity in a continuous duty cycle up to 8,760 hr/yr.

Ash Handling System Controls

Dust from the ash silo systems will be controlled by fabric filter dust collectors. Ash for sale will be conveyed pneumatically to enclosed rail cars or trucks with dust controlled by fabric filter dust collectors. Ash transported to the on-site landfill will be mixed with water in a rotary mixer to control dust during transport and disposal. The landfill permit will outline operating requirements to control dust. The combustion waste will be covered with topsoil and revegetated after active areas of the disposal site are filled to permitted design elevations.

2.2.3 Cooling System

Cooling System Design

The proposed cooling system design will be a hybrid system consisting of both air-cooled (dry) condensers and a mechanical draft wet cooling system. The system is designed to conserve water and to lower particulate emissions (from dissolved solids in water) when load and atmospheric conditions are favorable for heat rejection by using large volumes of air to dissipate heat. The mechanical draft wet cooling towers will be used for evaporation cooling during higher load operations and when atmospheric conditions are less favorable for heat rejection.

Steam created in each unit will be expanded through a steam turbine and converted to water in the condenser system of each unit. The condenser is a large heat exchanger where steam is condensed. The condensate from the condenser will be returned to the plant as feed water to be reused in the steam cycle. Heat rejected from the condenser will be transferred to a hybrid air- and water-cooled condenser system. The water-cooled portion of the system will pump circulating water to the cooling tower, where it will be distributed through the structural fill and then fall to the bottom of the tower. The warm droplets of water will be cooled by an air flow pulled through the cooling tower by fans at the top of the cooling tower. The water may be circulated through the cooling tower several times before it is discharged for treatment and reuse or disposal.

Cooling System Operation

Both cooling towers will operate efficiently at maximum capacity in a continuous duty cycle up to 8,760 hr/yr.

Cooling System Control

No air emissions will be emitted from the air-cooled condensers. The mechanical draft wet cooling towers will lose water through evaporation. The quantity of water evaporated depends on the plant generation load. As a result of this evaporation, dissolved solids will increase as a function of time. The water level in the cooling tower basin will be controlled so that the amount of water evaporated is replenished with fresh water. Particulate emissions will be controlled by minimizing the release of water droplets that contain dissolved solids through drift eliminators. Drift eliminators consist of a series of baffles that reduce the amount of particulate-containing water droplets that can escape to the atmosphere.

2.2.4 Auxiliary Boiler System

Auxiliary Boiler System Design

The rated heat input of the auxiliary boiler is 220 million British thermal units per hour (mmBtu/hr). The auxiliary boiler will provide a backup steam source for startup, process needs, and building heating systems when the plant auxiliary steam system is inadequate.

Auxiliary Boiler System Operation

The auxiliary boiler may be operated when one or both main boilers is off line, to supplement the auxiliary steam system when the main boilers are in startup or being removed from service, and when the plant auxiliary steam is not capable of meeting the heating requirements. The auxiliary boiler will be the only source of auxiliary steam for plant heating when both main boilers are off line. Typically, an auxiliary boiler does not operate more than is required to meet seasonal building heating requirements and when supplemental process steam is needed.

Auxiliary Boiler System Controls

The auxiliary boiler unit will be fired by No. 2 fuel oil with a sulfur content of less than or equal to 0.0015 percent. Low NO_X burners (LNB) will be installed to control NO_X and CO emissions. Operation of the auxiliary boiler will be limited to 4,000 hours per year.

2.2.5 Ancillary Equipment

Ancillary Equipment Design

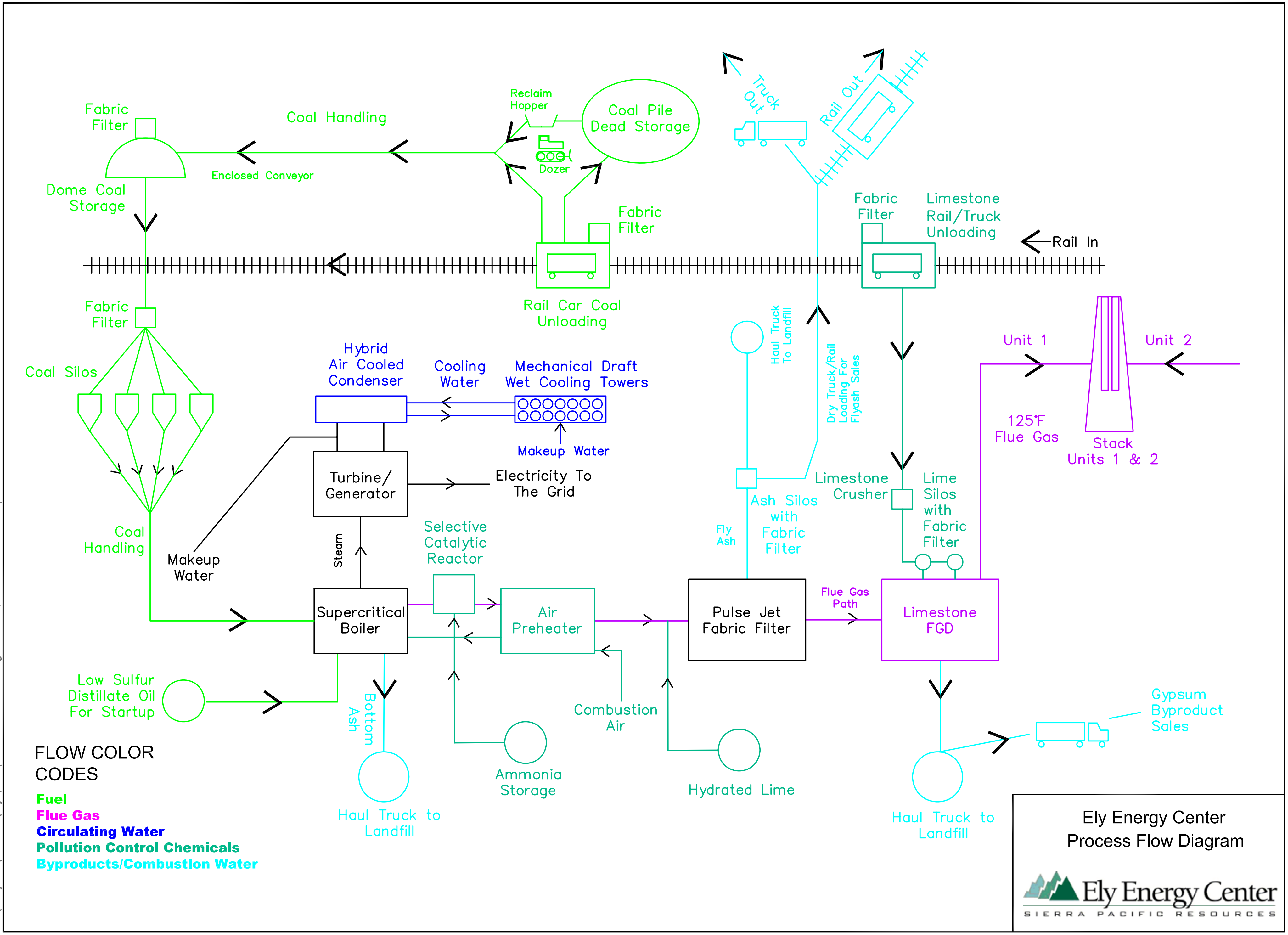
Ancillary equipment includes one plant diesel engine auxiliary generator, one diesel SO_2 absorber emergency quench pump, one switchyard diesel engine auxiliary generator, one diesel fire water pump, one diesel booster fire pump, and one propane spark-ignited communication auxiliary generator. The plant diesel engine auxiliary generator will fire low-sulfur diesel fuel and is rated at 4,650 horsepower (hp). The diesel SO_2 absorber emergency quench pump will fire low-sulfur diesel fuel and is rated at 683 horsepower. The switchyard diesel engine auxiliary generator will fire low-sulfur diesel fuel and is rated at 1,013 hp. The diesel fire water pump will fire low-sulfur diesel fuel and is rated at 788 hp. The diesel booster fire water pump will fire low-sulfur diesel fuel and is rated at 90 horsepower. The spark ignited communication auxiliary generator will fire propane and is rated at 80 horsepower.

Ancillary Equipment Operation

These diesel engines are designed to operate during testing and emergencies. Typically, these units each operate less than 250 hours per year. Each diesel engine will have a dedicated diesel fuel storage tank. The propane spark-ignited communication auxiliary generator typically operates less than 4,000 hours per year.

Ancillary Equipment Controls

These diesel engines will be supplied with current combustion controls and fired by low-sulfur distillate oil with a sulfur content less than or equal to 0.0015 percent and will include combustion controls to minimize NO_X and CO emissions. Their operation will be limited to 250 hours per year. The propane spark-ignited communication auxiliary generator will be limited to 4,000 hours per year.



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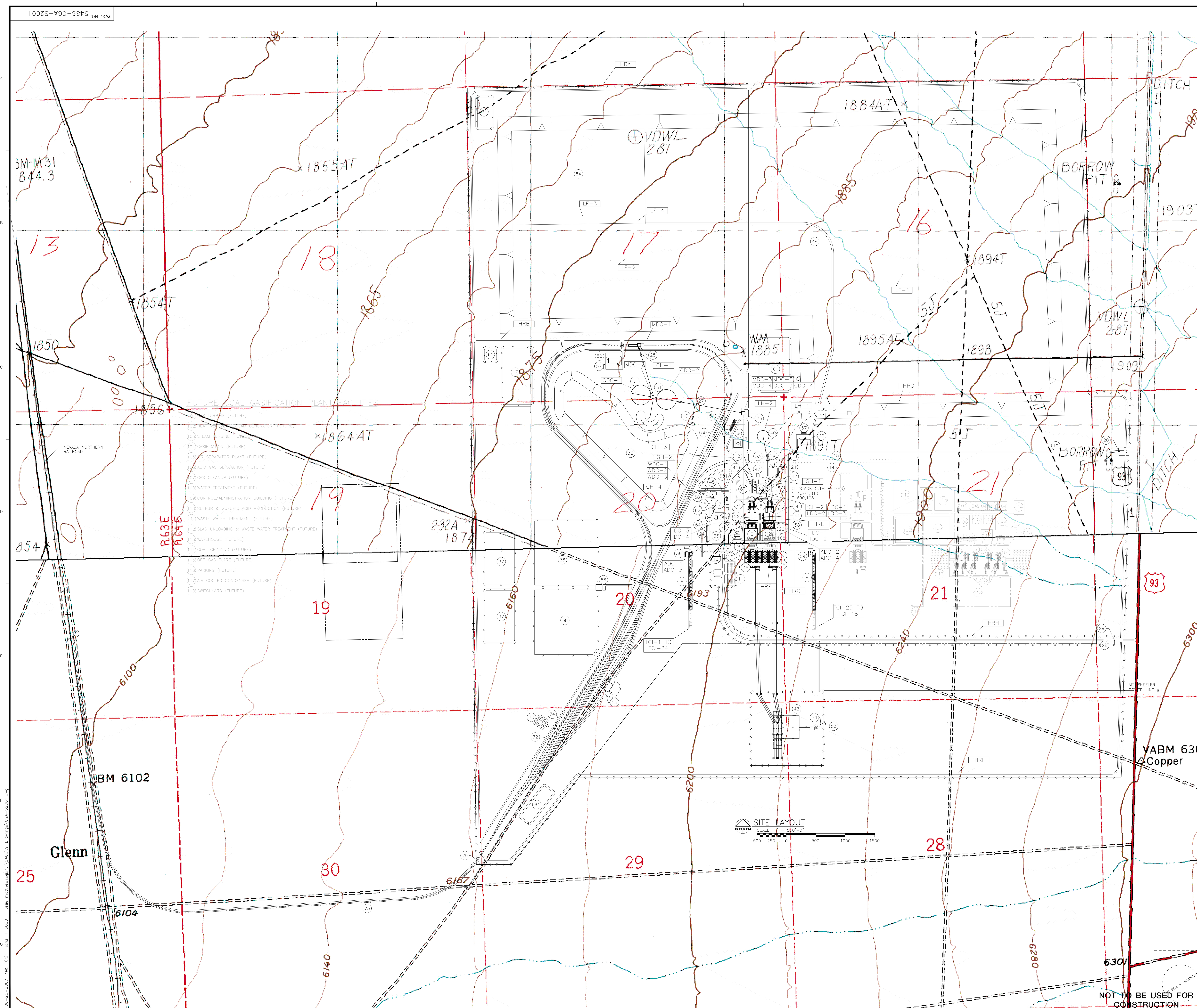

FACILITIES LEGEND

1. STEAM TURBINE GENERATOR (120')
2. BOILER (280')
3. AQCS WET FGD (120')
4. AQCS FABRIC FILTER (65')
5. STACK (727')
6. CONDENSATE STORAGE TANK (UNDER ACC) (34')
7. WATER/WASTE WATER TREATMENT (32')
8. COOLING TOWER (50')
9. ADMINISTRATION BUILDING (75')
10. EMERGENCY COAL RECLAIM
11. EMPLOYEE PARKING
12. MAKE-UP WATER TANKS (30')
13. WAREHOUSE BUILDING (24')
14. ASH/GYPSUM LOADOUT TRACK
15. LIMESTONE UNLOADING TRACK
16. LIMESTONE UNLOADING (32')
17. COAL PILE RUN-OFF POND
18. FLY ASH SILOS (125')
19. CONSTRUCTION ENTRANCE ROAD
20. CONSTRUCTION GUARD HOUSE (10')
21. ABSORBER HOLD TANK (50')
22. BOTTOM ASH SILO (100')
23. CRUSHER HOUSE (90')
24. TRUCK SCALE
25. ROTARY DUMPER (32')
26. SODA ASH
27. CONVEYOR TRANSFER TOWER #2 (40')
28. PLANT ACCESS ROAD
29. GUARD HOUSE (10')
30. COAL PILE DEAD STORAGE (40')
31. COAL LIVE STORAGE DOME (120')
32. LIMESTONE PREP/GYPSUM DEWATERING BLDG (85')
33. LIMESTONE CONVEYOR
34. AMMONIA STORAGE
35. PLANT MAINTENANCE BUILDING (40')
36. AIR COOLED CONDENSER (120')
37. EVAPORATION POND
38. SERVICE/FIRE WATER STORAGE POND
39. AUXILIARY BOILER
40. LIMESTONE STORAGE (55')
41. RECLAIM WATER TANK (15')
42. LIMESTONE SLURRY TANK (30')
43. SWITCHYARD
44. PAC SILO (70')
45. DEMINERALIZED WATER STORAGE TANK (40')
46. POTABLE WATER STORAGE TANK (15')
47. GYPSUM BUNKER (25')
48. LANDFILL
49. ASH HAUL TRUCK/LIGHT VEHICLE MAINT FACILITY (32')
50. SECONDARY/AUX BOILER DIESEL FUEL LOAD/UNLOAD STA
51. AMMONIA UNLOADING
52. COAL YARD TRUCK MAINTENANCE (32')
53. COMMUNICATION SHELTERS & MICROWAVE TOWER
54. 5-YEAR LANDFILL CELL
55. RAIL CAR OPERATION & MAINTENANCE FACILITY (32')
56. MAGNESIUM HYDROXIDE STORAGE SILO (100')
57. MOBILE EQUIPMENT FUELING
58. HYDRATED LIME STORAGE SILO (70')
59. CIRC WATER CHEM FEED EQUIPMENT
60. SECONDARY/AUX BOILER DIESEL FUEL STORAGE (46')
61. SITE STORM DETENTION POND
62. CLARIFIERS (30')
63. PLANT WASTEWATER SUMP & MAINTENANCE BASIN
64. SANITARY WATER TREATMENT PLANT
65. LIMESTONE/GYPSUM/ASH BASIN
66. SERVICE/FIRE WATER PUMP HOUSE (24')
67. FUTURE CO2 CAPTURE
68. BURNER D2 SUPPLY TANK (15')
69. FIRE BOOSTER PUMPS/STA AIR COMP/STANDBY GEN (24')
70. AUX BOILER/STANDBY GEN D2 SUPPLY TANK (15')
71. SWITCHYARD/COMMUNICATIONS AUXILIARY GENERATOR (10')
72. LOCOMOTIVE FUELING RACK
73. LOCOMOTIVE DIESEL FUEL STORAGE (30')
74. LOCOMOTIVE DIESEL FUEL LOAD/UNLOAD STA
75. INTERCONNECTING RAIL LOOP

REV.	DATE	DESCRIPTION	DWN	ENGR	CHK	APPV
F	12 APR 07	REVISED	TMS	JAC		
E	15 FEB 07	REVISED	TMS	JAC		
D	2 FEB 07	BOILER SPEC – FOR BIDS	TMS	JAC		
C	25 JAN 07	OWNER REVIEW	TMS			
H	26 JUNE 07	INCORPORATED COMMENTS	ELT			
G	25 MAY 07	REVISED	TMS			

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SIERRA PACIFIC RESOURCES

ELY ENERGY CENTER
PRELIMINARY SITE ARRANGEMENT
SOUTH STEPTOE VALLEY SITE

SCALE: 1=500' | PROJECT NO. 5486

DWG. NO. 5486-CGA-S2001 | REV. H

3.0 EMISSION ESTIMATE REFERENCES AND DOCUMENTATION

This section discusses the major emission units, criteria pollutant emissions estimates, hazardous air pollutant (HAP) emission estimates, and ammonia slip emissions estimates.

3.1 EMISSION UNITS

The major emission units are listed below, and the potential operation of each emission unit is estimated as follows:

- PC Boiler 1 (750 MW nominal), cooling system, fuel system, and ash system operated 8,760 hr/yr
- PC Boiler 2 (750 MW nominal), cooling system, fuel system, and ash system operated 8,760 hr/yr
- Auxiliary boiler (220 mmBtu/hr) operated 4,000 hr/yr
- Plant diesel engine auxiliary generator (4,650 hp) operated 250 hr/yr
- Diesel fire water pump (788 hp) operated 250 hr/yr
- Switchyard diesel engine auxiliary generator (1,013 hp) operated 250 hr/yr
- Diesel SO_2 absorber emergency quench pump (683 hp) operated 250 hr/yr
- Diesel booster fire pump (90 hp) operated 250 hr/yr
- Propane spark ignited communication auxiliary generator (80 hp) operated 4,000 hr/yr

The ambient air quality impacts from these emissions estimates do not exceed the National or Nevada AAQS or the PSD Class I or Class II air quality increments.

3.2 PSD REGULATED POLLUTANT EMISSIONS ESTIMATES

This section discusses the emissions data used to estimate potential PSD regulated pollutant emissions from the EEC, which include the following:

- NO_X
- SO_2
- Sulfuric acid (H_2SO_4) mist (New Source Review (NSR))
- CO
- VOC
- PM_{10}

- Lead
- Hydrogen fluoride (NSR)

Emissions from the PC boilers, auxiliary boiler, diesel engine generator, and diesel fire water pump are discussed below.

3.2.1 PSD Regulated Pollutants — PC Boilers 1 and 2

The PC boilers are equipped with low NO_X combustion systems, SCR systems for further reduction of NO_X, a fabric filter system to remove particulates and lead, and a wet FGD system for reduction of SO_2 and removal of acid gases (HF and sulfuric acid mist). Table 3-1 summarizes the expected emissions rates for these criteria pollutants.

TABLE 3-1
CALCULATED POLLUTANT EMISSIONS FOR PC BOILERS 1 AND 2

Pollutant Parameter	Control Equipment	Single Unit Hourly Emissions (lb/hr)	Single Unit Annual Emissions (ton/yr)	Two Units Annual Emissions (controlled) (ton/yr)
NO_X as NO_2	LNB, OFA, SCR	523	2,289	4,578
SO_2	FGD	697	2,289	4,578
Sulfuric acid mist	FGD, FF	34.8	152.6	305.2
CO	CC	871	3,815	7,630
VOC	CC	30.5	133.5	267
PM/PM_{10}	FF	174	763	1,526
Lead	FF	0.23	0.99	1.98
HF	FGD, FF	3.5	15.3	30.5

Notes:

CC	Combustion controls
CO	Carbon monoxide
FF	Fabric filter
FGD	Flue gas desulfurization
GOP	Good operating practice
H_2SO_4	Sulfuric acid
HF	Hydrofluoric acid
lb/hr	Pound per hour
LNB	Low NO_X burner
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
OFA	Over fire air
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
ton/yr	Ton per year
VOC	Volatile organic compound

3.2.2 PSD Regulated Pollutants — Auxiliary Boiler

The auxiliary boiler is rated at 1,571.5 gallons per hour (gal/hr) and may operate 8,760 hr/yr. Table 3-2 summarizes the expected emissions rates for PSD regulated pollutants from the auxiliary boiler.

TABLE 3-2
CALCULATED POLLUTANT EMISSIONS FOR AUXILIARY BOILER

Pollutant Parameter	Emission Factor [(a)] (lb/mmBtu)	Total Hourly Emissions [(b)] (lb/hr)	Total Annual Emissions [(c)] (ton/yr)
NO_X	0.1	22.0	96.4
SO_2	0.05	11.0	48.2
CO	0.036	7.92	34.7
VOC	0.0018	0.40	1.73
PM/PM_{10}	0.02	4.4	19.3

Notes:

CO	Carbon monoxide	PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
lb/hr	Pound per hour		
lb/mmBtu	Pound per million British thermal units	SO_2	Sulfur dioxide
NO_X	Nitrogen oxides	ton/yr	Ton per year
PM	Particulate matter	VOC	Volatile organic compound

(a) Emissions data source: Cummins & Bernard
(b) Emissions rate (lb/hr) = Heat input (mmBtu/hr) x Emission factor (lb/mmBtu)
(c) Annual emissions (ton/yr) = Heat input (mmBtu/hr) x Emission factor (lb/mmBtu) x 4,000 annual operating hour (hr/yr) ÷ 2,000 (lb/ton)
Fuel usage = 1,571.43 gal/hr
Annual hours = 4,000 hr/yr

3.2.3 PSD Regulated Pollutants — Plant Diesel Engine Auxiliary Generator

A 3,000 kW (4,650-hp) diesel engine generator will be installed to protect critical systems during a power outage. The generator will operate less than 250 hr/yr. Table 3-3 summarizes expected emissions for PSD regulated pollutants based on diesel engine generator design information. The plant diesel engine auxiliary generator and the auxiliary boiler will have a dedicated 15,000 gallon diesel storage tank.

TABLE 3-3
CALCULATED POLLUTANT EMISSIONS FOR PLANT DIESEL ENGINE AUXILIARY GENERATOR

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	37.0	4.6
SO_2	0.019	0.0024
CO	23.1	2.89
VOC	5.3	0.66
PM/PM_{10}	1.3	0.17

Notes:

CO Carbon monoxide
lb/hr Pound per hour
NO_X Nitrogen oxide
PM Particulate matter
PM_{10} Particulate matter with an aerodynamic diameter less than 10 microns
SO_2 Sulfur dioxide
ton/yr Ton per year
VOC Volatile organic compound

3.2.4 PSD Regulated Pollutants — Diesel Fire Water Pump

A 788-hp diesel fire water pump will be installed for fire protection. The fire pump will operate no more than 250 hr/yr. Table 3-4 summarizes expected emissions for PSD regulated pollutants from the diesel fire water pump. The diesel fire water pump will have a dedicated 700 gallon storage tank.

TABLE 3-4
CALCULATED POLLUTANT EMISSIONS FOR DIESEL FIRE WATER PUMP

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	7.3	0.91
SO_2	0.003	0.0004
CO	4.5	0.56
VOC	1.0	0.13
PM/PM_{10}	0.3	0.033

Notes:

CO Carbon monoxide
lb/hr Pound per hour
NO_X Nitrogen oxide
PM Particulate matter
PM_{10} Particulate matter with an aerodynamic diameter less than 10 microns
SO_2 Sulfur dioxide
ton/yr Ton per year
VOC Volatile organic compound

3.2.5 PSD Regulated Pollutants — Switchyard Diesel Engine Auxiliary Generator

A 750-kW (1,013-hp) switchyard diesel engine auxiliary generator will be installed for backup power in the switchyard during a power outage. The auxiliary generator will operate no more than 250 hr/yr. Table 3-5 summarizes expected emissions for PSD regulated pollutants from the switchyard diesel engine auxiliary generator. The switchyard diesel engine auxiliary generator will have a dedicated 700 gallon storage tank.

TABLE 3-5
CALCULATED POLLUTANT EMISSIONS FOR SWITCHYARD DIESEL ENGINE AUXILIARY GENERATOR

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	9.3	1.2
SO_2	0.004	0.0005
CO	5.8	0.72
VOC	1.3	0.165
PM/PM_{10}	0.3	0.04

Notes:

CO	Carbon monoxide
lb/hr	Pound per hour
NO_X	Nitrogen oxide
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
SO_2	Sulfur dioxide
ton/yr	Ton per year
VOC	Volatile organic compound

3.2.6 PSD Regulated Pollutants — Diesel SO_2 Absorber Emergency Quench Pump

A 683-hp diesel absorber quench pump will be installed for cooling the SO_2 absorbers during a power outage. The quench pump will operate no more than 250 hr/yr. Table 3-6 summarizes expected emissions for PSD regulated pollutants from the diesel quench pump. The SO_2 absorber emergency quench pump will have a dedicated 700 gallon storage tank.

TABLE 3-6
CALCULATED POLLUTANT EMISSIONS FOR DIESEL SO_2 ABSORBER QUENCH PUMP

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	3.9	0.5
SO_2	0.003	0.0003
CO	3.9	0.49
VOC	0.6	0.07
PM/PM_{10}	0.2	0.03

Notes:

CO	Carbon monoxide
lb/hr	Pound per hour
NO_X	Nitrogen oxide
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
SO_2	Sulfur dioxide
ton/yr	Ton per year
VOC	Volatile organic compound

3.2.7 PSD Regulated Pollutants — Diesel Booster Fire Pump

A 90-hp diesel booster fire pump will be installed for maintaining fire water flow ratings at boiler elevations during power outages. The booster pump will operate no more than 250 hr/yr. Table 3-7 summarizes expected emissions for PSD regulated pollutants from the diesel booster fire pump. The diesel booster fire water pump will have a dedicated 200 gallon storage tank.

TABLE 3-7
CALCULATED POLLUTANT EMISSIONS FOR DIESEL BOOSTER FIRE WATER PUMP

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	0.6	0.078
SO_2	0.0004	0.00005
CO	0.7	0.092
VOC	0.09	0.011
PM/PM_{10}	0.06	0.007

Notes:

CO	Carbon monoxide
lb/hr	Pound per hour
NO_X	Nitrogen oxide
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
SO_2	Sulfur dioxide
ton/yr	Ton per year
VOC	Volatile organic compound

3.2.8 PSD Regulated Pollutants — Propane Spark-Ignited Communication Auxiliary Generator

An 80-hp propane auxiliary generator will be installed for providing electric power for communication equipment during construction and plant operation during power outages. The communication auxiliary generator will operate no more than 4,000 hr/yr. Table 3-8 summarizes expected emissions for PSD regulated pollutants from the propane spark-ignited communication auxiliary generator. The communication auxiliary generator will have a dedicated propane storage tank.

TABLE 3-8
CALCULATED POLLUTANT EMISSIONS FOR PROPANE COMMUNICATION AUXILIARY GENERATOR

Pollutant Parameter	Design Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
NO_X	0.19	0.38
SO_2	0.015	0.03
CO	0.03	0.06
VOC	0.005	0.01
PM/PM_{10}	0.006	0.01

Notes:

CO	Carbon monoxide
lb/hr	Pound per hour
NO_X	Nitrogen oxide
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
SO_2	Sulfur dioxide
ton/yr	Ton per year
VOC	Volatile organic compound

3.3 HAZARDOUS AIR POLLUTANT EMISSIONS ESTIMATES

A substance is designated as a hazardous air pollutant (HAP) by regulation of the Nevada State Environmental Commission, adopted by reference from the U. S. Environmental Protection Agency (EPA), and the HAPs are listed in 42 U.S.C. § 7412(b). Table 3-9 summarizes the HAP emissions for proposed sources at the EEC. HAP emissions include those from the combustion sources, material handling operations, and locomotive engines.

3.4 AMMONIA SLIP EMISSION ESTIMATES

Ammonia will be used in the SCR process to reduce NO_X emissions. Ammonia that is not reacted in the SCR process will pass through the SCR catalyst bed, the fabric filter system, and the FGD system and will be emitted to the atmosphere. The flue gas emissions, commonly called “ammonia slip,” are not expected to exceed a concentration of 5 parts per million (ppm).

TABLE 3-9
CALCULATED HAP EMISSIONS

Pollutant	Total Annual Emissions (ton/yr)	Pollutant	Total Annual Emissions (ton/yr)
Acetaldehyde	2.69	Methyl methacrylate	0.09
Acetophenone	0.07	Methyl tert butyl ether	0.16
Acrolein	1.37	Methylene chloride	0.24
Benzene	6.22	Naphthalene	0.08
Benzyl chloride	3.30	Phenol	0.08
Biphenyl	0.01	Propionaldehyde	1.79
Bis(2-ethylhexyl)phthalate (DEHP)	0.34	Propylene	0.36
Bromoform	0.18	Styrene	0.12
1,3 – Butadiene	2.51E-05	Tetrachloroethylene	0.20
Carbon disulfide	0.61	Toluene	1.17
2-Chloroacetophenone	0.03	1,1,1-Trichloroethane (Methyl chloroform)	0.09
Chlorobenzene	0.10	Vinyl acetate	0.04
Chloroform	0.28	Xylenes	0.20
Cumene	0.02	Antimony	0.09
Dimethyl sulfate	0.23	Arsenic	2.01
2,4-Dinitrotoluene	0.00	Beryllium	0.10
Ethyl benzene	0.44	Cadmium	0.24
Ethyl chloride	0.20	Chromium	1.25
Ethylene dichloride	0.19	Chromium VI	0.37
Ethylene dibromide	0.01	Cobalt	0.47
Formaldehyde	1.56	Hydrogen chloride	847.79
Hexane	0.32	Hydrogen fluoride	30.53
Isophorone	2.73	Manganese	2.38
Methyl bromide	0.75	Mercury	0.15
Methyl chloride	2.50	Nickel	1.37
Methyl hydrazine	0.80	Selenium	6.14

Notes:
HAP Hazardous air pollutant
ton/yr Ton per year

4.0 APPLICABLE REQUIREMENTS

This section presents the review of both Nevada and federal air quality regulations and identifies the regulations that apply to permitting the EEC. Nevada has adopted federal regulations by reference and incorporated them within NAC Chapter 445B.

4.1 AMBIENT AIR QUALITY STANDARDS

The Nevada AAQS are presented in NAC Chapter 445B.22097. The Nevada AAQS are equal to or more stringent than the National AAQS. The Nevada and National AAQS are discussed in Appendix A9, which presents the air quality modeling approach.

Compliance Demonstration: This permit application presents an air quality impact analysis (AQIA) (Appendix A9) for the proposed project that demonstrates that the proposed EEC will not cause or adversely affect the ability to comply with applicable AAQS.

4.2 PREVENTION OF SIGNIFICANT DETERIORATION AIR QUALITY AND INCREMENTS

This section incorporates federal PSD rules contained in 40 CFR Parts 51 and 52. The proposed EEC project is subject to these requirements based on the anticipated quantity of pollutants released to the atmosphere. The most significant PSD requirements are (1) the use of BACTs to minimize air emissions from the proposed EEC, (2) the AQIA, and (3) the protection of PSD increments and of air quality-related values (AQRV) in Class I areas as a result of these controls. Besides the compliance demonstration for these PSD requirements, the paragraphs below discuss the protection of AQRVs and the PSD growth evaluation.

Compliance Demonstration: This permit application presents a control technology analysis that demonstrates that BACTs will be used on the proposed project (Appendix B). The permit application also presents an AQIA carried out in accordance with the requirements of 40 CFR Parts 51 and 52 (Appendix A9).

In addition to AAQS, it is necessary for ambient impacts to maintain compliance with PSD increments. PSD increments are limits on the incremental increase in impacts to ambient air and are defined in NAC Chapter 445B.087 as the same as the national PSD increments. Class I increments apply to federally protected national parks, wildlife areas, and wilderness areas. All other areas are subject to PSD increment protection designated as Class II increments. The PSD Class I and Class II increment impact analyses for the proposed EEC demonstrate that the proposed EEC will not cause or significantly contribute to any exceedances of the applicable PSD increments.

Protection of Air Quality Related Values (AQRV): The AQRVs are attributes of a Class I area that deterioration of air quality may adversely affect. Appendix A9 presents the AQRV analysis. The AQRVs generally are expressed in broad terms, and the impacts of increased pollutant levels on some AQRVs are assessed by measuring specific parameters that reflect the AQRV's status. The AQRVs include protection of scenic values as well as projected pollutant impacts on the presence and vitality of certain animal or plant species, including species diversity or preservation of certain endangered species. An AQRV associated with water quality may be measured as the pH of a water body or may be based on the level of certain nutrients in the water. The AQRVs for various Class I areas differ depending on the purpose and characteristics of a particular area and on assessments by the area's federal land manager.

PSD Growth Evaluation: The PSD process includes an evaluation of growth and its potential environmental impact. The proposed EEC project is consistent with the 2006 resource plan submitted to the Nevada Public Utilities Commission for meeting a portion of the projected load growth in both northern and southern Nevada.

Growth in the Ely area created by the construction labor force may result in additional housing, traffic during trips to and from Ely, and infrastructure development in the surrounding area. Air quality impacts from this growth are expected to be temporary and may result from motor vehicle emissions, fugitive emissions from housing construction, and emissions from new commercial and residential heating sources.

The area is currently in attainment for all criteria pollutants. The additional pollutant loading from temporary and permanent growth in Ely is not expected to adversely affect maintenance of air quality standards in the area. A more detailed evaluation of the environmental impacts of the proposed facility will be contained in the environmental impact statement for the EEC.

4.3 NAC ALLOWABLE EMISSIONS

The NAC includes allowable emissions regulations for visible emissions, PM, and sulfur. NAC allowable emissions regulations that apply to the proposed EEC are discussed below.

Visible Air Contaminants: NAC Chapter 445B.22017 restricts visible emissions from the proposed project to no more than 20 percent opacity. The main boilers are granted an exception for a maximum 27 percent opacity for one 6-minute period per hour.

Compliance Demonstration: A continuous monitor at the main power plant will record the opacity in the baghouse outlet duct. Opacity will be maintained in accordance with 40 CFR Part 60, Appendix B, Performance Specification 1.0. The internal combustion engines will use combustion controls to limit visible emissions. All fugitive emissions from material handling of coal, limestone, and ash will be controlled by conveyor or building enclosures, dust collection systems, lowering wells, telescoping chutes, and fabric filter systems, as may be appropriate for each individual system. The equipment will be serviced on a regular basis, and visible emissions will be determined. All ash disposed of in the ash landfill will be wetted during loading into haul trucks so that visible emissions from fugitive sources such as transport and unloading will be minimized. Good operating practices will be maintained at the landfill. Water tankers will wet haul roads as needed to mitigate visible emissions from fugitive particulate emissions.

Particulate Matter: NAC Chapter 445B.2203 regulates emissions of PM_{10} from combustion operations on a pound per million British thermal unit (lb/mmBtu) basis, depending on the heat input per hour to the combustion device.

The full load heat input to each proposed PC boiler is 8,710 mmBtu/hr, making the boilers subject to NAC Chapter 445B.2203.1(c) for units equal to or greater than 4,000 mmBtu/hr of heat input. The equation in NAC Chapter 445B.2203.1(c) results in a calculated NAC PM_{10} limit of 0.098 lb/mmBtu from each boiler.

The heat input to the proposed auxiliary boiler is 220 mmBtu/hr, making the unit subject to NAC Chapter 445B.2203.1(b) for units greater than 10 mmBtu/hr and less than 4,000 mmBtu/hr. The equation in NAC Chapter 445B.2203.1(b) results in a calculated NAC PM_{10} emission limit for the auxiliary boiler of 0.29 lb/mmBtu.

NAC Chapter 445B.22033 regulates particulate emissions from sources not limited by NAC Chapters 445B.2203 or 445B.22037. This regulation limits particulate emissions on a pound per hour (lb/hr) basis depending on the tons per hour (tons/hr) of throughput through the emission unit.

NAC Chapter 445B.22037 restricts particulate emissions from industrial operations (non-combustion) by requiring the use of "best practical methods" to prevent PM fugitive dust emissions. This regulation applies to non-combustion sources associated with the EEC project, such as material handling.

Compliance Demonstration: The permit application presents particulate emissions rates from each source. Each of these rates is below the allowable rates presented in the regulations discussed above. Gas cleaning devices have been implemented to reduce particulate emissions and are identified on the forms in Appendix A. Six uncontrolled internal combustion engines, the fire water pump, the booster fire pump, the SO_2 absorber emergency quench pump, two diesel engine generators, and one propane fired engine generator will be run intermittently.

Sulfur Compounds: NAC Chapter 445B.22047 restricts emissions of sulfur from fuel-burning units. This regulation limits sulfur emissions on a lb/hr basis depending on the mmBtu/hr heat input to the combustion device. The full-load heat input to each proposed PC boiler is 8,710 mmBtu/hr, making the boilers subject to NAC Chapter 445B.22047.3 for boilers more than 250 mmBtu/hr. The formula in NAC Chapter 445B.22047.3 results in a calculated sulfur limit of 5,226 lb/hr from each boiler.

Compliance Demonstration: The permit application presents sulfur emission rates for each combustion source. The internal combustion engines are run intermittently and combust a low sulfur diesel that contains 0.0015 percent or less sulfur by weight. All SO_2 emissions rates are below the standard.

Emissions from Generators and Fire Pumps: The facility is proposing to install several generators and fire pumps. The diesel engine auxiliary generator (7.89 mmBtu/hr and 3,100 hp) will comply with the particulate matter and sulfur emission requirements of NAC 445B.223 and NAC 445B.2204. In addition, this generator will comply with the emission rates and requirements listed in 40 CFR Part 60 Subpart IIII, which will be incorporated in NAC 445.221(5).

The other units include a diesel fire pump (0.15 mmBtu/hr and 525 hp), a switchyard diesel engine auxiliary generator (1.72 mmBtu/hr and 675 hp), a diesel SO_2 absorber emergency quench pump (1.16 mmBtu/hr and 455 hp), a diesel booster fire pump (0.15 mmBtu/hr and 60 hp), and a propane spark-ignited communication auxiliary generator (0.20 mmBtu/hr and 80 hp). The maximum heat input rate for these units is less than 4 mmBtu/hr each. These units are exempt from the particulate and sulfur emission rate requirements of NAC 445B.223 and NAC

445B.2204. However, they must comply with the emission rates and other requirements listed in 40 CFR Part 60 Subpart IIII, which will be incorporated in NAC 445.221(5).

4.4 STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

NAC Chapter 445B.221 incorporates by reference all the federal New Source Performance Standards (NSPS) promulgated by the U.S. EPA in 40 CFR Part 60 (EPA 2006c). The NSPS that apply to the proposed EEC project include the following:

- Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- Subpart Y – Standards of Performance for Coal Preparation Plants
- Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants
- Subpart HHHH – Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Each NSPS is discussed below.

Subpart Da: The emission standards contained in Subpart Da for electric utility steam generating units are applicable to the PC boilers as outlined below. In addition, Subpart Da contains regulatory provisions on compliance, monitoring, performance testing, and reporting, which are not repeated in this document.

Particulate Matter

40 CFR 60.42Da

(c) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005 except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain PM in excess of either:

(1) 18 nanograms per joule (ng/J) (0.14 pounds per megawatt hour [lb/MWh]) gross energy output; or

(2) 6.4 ng/J (0.015 lb/mmBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM matter in excess of:

(1) 13 ng/J (0.03 lb/mmBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent removal) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent removal) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

<u>Sulfur Dioxide</u>

40 CFR 60.43Da

(i) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/[megawatt-hour] MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent removal) on a 30-day rolling average basis.

Nitrogen Oxides

40 CFR 60.44Da

(e) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an integrated gasification combined cycle (IGCC) meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

Mercury

40 CFR 60.45Da

(a)(2) For each coal-fired electric utility steam generating unit that burns only sub-bituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 66 x 10^{-6} lb/MWh or 0.066 pound per gigawatt-hour (lb/GWh) on an output basis. The International System of Units (SI) equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 97 x 10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

The applicable mercury emission limit in federal regulation (40 CFR 60.45 Da) is 97 x 10^{-6} lb/MWh because Ely, Nevada, has averaged approximately 9.6 inches of annual precipitation over the past 100 years (Western Regional Climate Center 2006).

Under the Nevada Clean Air Mercury Rule (CAMR), sources that voluntarily install controls meeting the low emitting unit criteria will be eligible to apply for incentive allowances based on a two-level approach. New mercury budget units will qualify as level I units if they meet the output-based maximum achievable control technology (MACT) standards for new units that were proposed by EPA in 2004 (69 FR 4652) and as level II units if they meet 80 percent of the performance standards for mercury promulgated in the CAMR. The applicable level I and level II qualifying criteria for mercury budget units in the proposed EEC are below.

Level I mercury budget unit For new mercury budget units operated on the following fuel: Sub-bituminous coal with wet FGD	Mercury emission rate not to exceed: 20 x 10^{-6} lb/MWh
Level II mercury budget unit For new mercury budget units operated on the following fuel: Sub-bituminous coal with wet FGD	Mercury emission rate not to exceed: 53 x 10^{-6} lb/MWh

Subpart Db: The emission standards contained in Subpart Db for industrial steam-generating units that apply to the auxiliary boiler are outlined below. In addition, Subpart Db includes regulatory provisions on compliance, monitoring, performance testing, and reporting, which are not repeated in this document.

<u>Nitrogen Oxides</u>

40 CFR 60.44(b)

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

Fuel/Steam generating unit type	Nitrogen oxide emission (lb/million Btu)
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate	0.10
(ii) High heat release rate	0.20

Subpart Y: Subpart Y is presented in 40 CFR 60.250(a). The provisions of this subpart apply to any of the following affected facilities in coal preparation plants that process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

On and after the date when the performance test required to be conducted by 40 CFR 60.252(c) is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere any gases that exhibit 20 percent opacity or greater from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system. Method 9 and the procedures in 40 CFR 60.254(b)(2) are used to determine opacity.

Subpart OOO: The emission standards in Subpart OOO apply to lime processing operations at the EEC. The EEC will comply with the monitoring, testing, reporting, and recordkeeping requirements of this subpart.

Subpart HHHH: The EEC must meet the NSPS contained in the CAMR and detailed in 40 CFR 60 Subpart HHHH because the proposed EEC is considered a "new coal-fired power plant" and construction will begin on or after January 30, 2004. The permit application presents mercury emission rates from the coal-fired boilers. Section 4.5 further discusses mercury control and Nevada requirements for mercury emissions.

Subpart IIII: On July 11, 2006, new standards of performance for stationary compression ignition internal combustion engines were set up under 40 CFR Part 60, Subpart IIII. These regulations apply to the diesel engine generators, fire water pumps, and diesel SO_2 absorber quench pump at the EEC. Table 4-1 lists specific emission limits fire water pumps, and Table 4-2 lists specific emission limits for diesel engine generators.

TABLE 4-1
EMISSION STANDARDS FOR EMERGENCY FIRE PUMP ENGINES

Maximum Engine Power	Emissions Standards g/kW-hr (g/hp-hr)			
	Model year(s)	**NMHC + NO_X**	**CO**	**PM**
$300 \leq hp < 600$	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[a]	4.0 (3.0)		0.20 (0.15)

Notes:

CO	Carbon monoxide	NMHC	Non-methane hydrocarbon
g/hp-hr	Gram per horsepower hour	NO_X	Nitrogen oxide
g/kW-hr	Gram per kilowatt hour	PM	Particulate matter
hp	Horsepower		

a Emergency fire pump engines with a rated speed of greater than 2,650 rpm are allowed an additional 3 years to meet these standards.

Source: 40 CFR Part 60, Subpart IIII, Table 4

TABLE 4-2
EMISSION STANDARDS FOR STATIONARY DIESEL ENGINE GENERATOR

Maximum Engine Power	Emissions Standards g/KW-hr (g/HP-hr)				
	Model years	**HC**	**NO_X**	**CO**	**PM**
hp > 750	Pre-2007 and 2007-2010 with engines >3,000 HP	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Notes:

CO	Carbon monoxide	HC	Hydrocarbon
g/hp-hr	Gram per horsepower hour	NO_X	Nitrogen oxide
g/KW-hr	Gram per kilowatt hour	PM	Particulate matter
hp	Horsepower		

Sources: 40 CFR 89.112 Table 1 and 40CFR Part 60, Subpart IIII, Table 1, as stated in 40 CFR §§ 60.4201(b), 60.4202(b), 60.4204(a) and 60.4205(a)

4.5 CLEAN AIR MERCURY RULE

On May 18, 2005, EPA issued the final CAMR (EPA 2005b), which builds on EPA's Clean Air Interstate Rule (CAIR) to significantly reduce mercury emissions from coal-fired power plants by nearly 70 percent. The CAMR establishes "standards of performance" for mercury, limiting emissions from new and existing utilities and creating a market-based, cap-and-trade program to reduce national utility emissions in two phases. The first phase involves a 38-ton-per-year (ton/yr) mercury cap due by 2010 as a "co-benefit" reduction, meaning that mercury emissions will be reduced concurrently with SO_2 and NO_X emissions under Clean Air Interstate Rule (CAIR) requirements. The second phase, due in 2018, will subject coal-burning utilities to a second cap to reduce mercury in stack emissions nationwide from 48 to 15 ton/yr when the standard is fully implemented.

On September 18, 2006, in response to the EPA CAMR, the State of Nevada amended NAC Chapter 445B to include a new program to control air emissions of mercury from coal-fired electric utility steam generating units (LCB File No. R162-06). The program developed by NDEP modifies the EPA cap-and-trade program described in the EPA CAMR, incorporating by reference certain provisions of the CAMR and adopting other provisions. Under the federal CAMR, each state will receive an annual "mercury emissions budget" for coal-fired electric utility steam generating units. The federal CAMR allocates to Nevada a budget of 570 pounds per year (lb/yr) of mercury from 2010 to 2017. After 2017, Nevada's budget will be 224 lb/yr.

The Nevada CAMR program will require power plants with coal-fired electric utility steam generating units to obtain a mercury permit to construct and a permit to operate. Through the permitting process and beginning in 2010, NDEP will allocate annual mercury emissions allowances to existing power plants based on projected annual emissions. Remaining annual allowances from the state budget will be maintained in a pool to be administered by NDEP. The pool will be used for new power plants, for incentive programs, and to support NDEP program needs, or allowances may be retired from the pool.

The major objective of Nevada's CAMR program is to encourage reduction of mercury emissions at existing facilities and encourage new facilities to install units that emit less mercury. The state will accomplish this reduction by offering bonus emissions allowances to facilities that install equipment or systems that reduce emissions below the allowances.

The Nevada regulation will affect new and existing coal-fired electric utility steam generating units. Power plants with coal-fired units will be required to install and operate mercury-specific

CEMS. Power generation companies will also be subject to the Nevada CAMR permitting program and applicable fees. New coal-fired units will have to meet the emissions requirements under the applicable regulations (SEC Reference P2006-18, Nevada State Environmental Commission 2006). Table 4-3 summarizes mercury emissions requirements.

TABLE 4-3
MERCURY EMISSIONS

Level I [a]	**Emissions Limit**
Existing Units	
Bituminous coal	21×10^{-6} lb/MWh
Sub-bituminous coal with wet FGD	61×10^{-6} lb/MWh
Sub-bituminous coal with dry FGD	61×10^{-6} lb/MWh
New Units	
Bituminous coal	6×10^{-6} lb/MWh
Sub-bituminous coal with wet FGD	20×10^{-6} lb/MWh
Sub-bituminous coal with dry FGD	20×10^{-6} lb/MWh
IGCC Technology	20×10^{-6} lb/MWh
Level II	
Existing Units [b]	
Bituminous coal	24×10^{-6} lb/MWh
Sub-bituminous coal with wet FGD	66×10^{-6} lb/MWh
Sub-bituminous coal with dry FGD	97×10^{-6} lb/MWh
New Units [c]	
Bituminous coal	16×10^{-6} lb/MWh
Sub-bituminous coal with wet FGD	53×10^{-6} lb/MWh
Sub-bituminous coal with dry FGD	78×10^{-6} lb/MWh

Notes:

FGD Flue gas desulfurization lb/MWh Pound per megawatt-hour
IGCC Integrated gasification combined cycle

(a) EPA's January 30, 2004, New Source Performance Standards (EPA 2004)
(b) EPA's October 28, 2005, New Source Performance Standards (EPA 2005c)
(c) 80 percent of EPA's October 28, 2005 New Source Performance Standards (EPA 2005c)

The maximum estimated mercury emissions are based on the selected BACT control strategy for the design fuel.

4.6 NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS

EEC will be a major HAP source. On June 9, 2006, EPA published a final rule setting forth its determination that regulation of electric utility steam generating units under Section 112 of the *Clean Air Act* was neither necessary nor appropriate (EPA 2006a). Instead, EPA adopted the CAMR to control mercury emissions (see Section 4.5).

The auxiliary boiler will be fired exclusively by distillate oil. Emissions of PM, CO, and hydrochloric acid (HCl) from the auxiliary boiler will be subject to regulation under a MACT standard of a National Emission Standard for Hazardous Air Pollutants (NESHAP) as contained in 40 CFR Part 63 (EPA 2006b). The auxiliary boiler will be subject to the 40 CFR Subpart 63 DDDDD MACT standards under the large liquid fuel subcategory, which is described below.

> Large liquid fuel subcategory includes any water tube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 mmBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

The MACT standard in 40 CFR 63 DDDDD for the limited use gaseous fuel subcategory is summarized in the table below.

Source	Pollutant	Standard
New or reconstructed large liquid fuel	PM	0.03 lb/mmBtu of large liquid fuel heat input
	HCl	0.0009 lb/mmBtu of heat input
	CO	400 ppm by volume on a dry basis corrected to 3 percent oxygen (O_2) (30-day rolling average)

The proposed auxiliary boiler will be capable of meeting the MACT standards in the table above.

Compliance Demonstration: The permit application presents emissions for each source at EEC. The emission levels presented are all lower than the standards discussed above. A CEMS will be installed for the PC boilers. The CEMS will monitor emissions for opacity, SO_2, NO_X, CO_2, and heat input. The PC boiler will also apply BACTs, as discussed in the BACT analysis (see Appendix B) and monitoring equipment to meet the CAMR requirements.

4.7 OPERATING PERMIT TO CONSTRUCT, CLASS I OPERATING PERMIT

NAC Chapters 445B.287 through 445B.3447 describe the requirements for obtaining a State of Nevada Operating Permit to Construct and a Class I Operating Permit. The proposed EEC is required to obtain an Operating Permit to Construct and a Class I Operating Permit because it will be a major source of air pollutants.

Compliance Demonstration: This permit application fulfills the requirements for an operating permit to construct. A separate Class I Operating Permit application will be prepared before the EEC completes 1 year of full operation.

4.8 STACK HEIGHTS

The effective stack height used in dispersion modeling is limited by good engineering practices (GEP). The GEP stack height refers to the greater of the following measurements:

- 213 feet measured from the ground-level elevation at the base of the stack
- For stacks whose construction commenced after January 12, 1979, a stack height established by the following equation:

$$Hg = H + 1.5\ L$$

where

Hg	=	GEP stack height measured from ground-level elevation at base of stack
H	=	Height of nearby structures measured from ground-level elevation at base of the stack
L	=	Lesser dimension, height or projected width, of nearby structures

- The height demonstrated by a fluid model or a field study approved by the Director of the Nevada Department of Conservation and Natural Resources or his designee that ensures that emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features

Compliance Demonstration: The permit application shows that all dispersion modeling was performed with a stack height that complies with the requirements of NAC Chapters 445B.287 through 445B.3447. The main boiler stack height exceeds 213 feet.

4.9 VISIBILITY PROTECTION

The AQRVs are attributes of a Class I area that deterioration of air quality may adversely affect. The AQRVs generally are expressed in broad terms, and the impacts of increased pollutant levels on some AQRVs are assessed by measuring specific parameters that reflect the AQRV's status. Protection of scenic values, as well as wildlife and vegetation, are included in AQRVs. The projected impact on the presence and vitality of certain species of animals or plants may indicate the impact of pollutants on AQRVs associated with species diversity or with the preservation of certain endangered species. An AQRV associated with water quality may be measured by the pH of a water body or the levels of certain nutrients in the water. The AQRVs of various Class I areas differ depending on the purpose and characteristics of a particular area and on assessments by the area's federal land manager.

Under 40 CFR 52, a visibility impact analysis is required for a proposed major stationary source. The analysis must use acceptable visibility models and demonstrate that the proposed project will not have or contribute to an adverse impact on visibility in any federal Class I area.

Compliance Demonstration: This permit application presents the visibility impact analysis in Appendix A9. The analysis demonstrates no adverse impact in federal Class I areas from the proposed EEC.

4.10 ACID RAIN PROGRAM

The Clean Air Act and the requirements of 40 CFR Part 75 establish a nationwide acid rain control program that limits emissions of SO_2 and NO_X from coal-fired electrical generating units. Along with emission limitations, there are requirements for monitoring, testing, recordkeeping, and reporting. A facility must apply for a separate acid rain program permit at least 24 months before operations of the proposed unit begin.

Compliance Demonstration: An acid rain permit application will be prepared and submitted, and all requirements will be met in the future.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

A BACT analysis was performed for the EEC. Because of the length of the BACT analysis, it is included as a stand-alone document in Appendix B of this application. Integrated gasification control cycle (IGCC) is not included in the BACT analysis and is discussed here instead, along with the reason for its exclusion from the BACT analysis.

IGCC is an emerging technology for new coal-fired generation. The technology uses a combustion turbine generator in combination with a heat recovery steam generator and a steam turbine generator for power generation.

Compressed air, typically extracted from the compressor section of the combustion turbine, is used in the pressurized coal gasification process. The gasification process then uses this compressed air directly in an air-blown gasification process or, as O_2 separated from the air, in an oxygen-blown gasification process. Steam extracted from the heat recovery steam generator is also added to the gasification process. The fuel gas produced is further processed to remove PM, sulfur species, and other contaminants before it is re-introduced as fuel into the combustion section of the combustion turbine.

Several IGCC processes have been demonstrated by the U.S. Department of Energy and other national and international organizations in cooperation with various electric utilities. Some of the processes have achieved an operating status that encourages further development and standardization for future use. SPR has prior experience in IGCC through its involvement in the Piñon Pine Clean Coal IV demonstration project.

At the *20th Symposium on Western Fuels*, Dr. Robert Wayland presented “EPA’s Perspective on Cleaner Coal.” In his presentation, Dr. Wayland stated, “In the case of pulverized coal boilers, IGCC should not be considered as a control technology candidate for BACT” (Wayland 2006).

SPR has a near-term need for coal-based generation to provide greater fuel diversification and rate stability. In a study titled “Nevada Power IGCC Market Status and Feasibility Study, Performance and Estimate Report,” the Worley Parsons Group, Inc., presented the conclusion below (Worley Parsons Group, Inc. 2006).

> “In summary, IGCC is an emerging technology which has some potential advantages with respect to Pulverized Coal, especially in emissions and efficiency. However, the costs, performance, availability, reliability and

maintainability of the new generation of IGCC systems are yet to be demonstrated."

Industry concerns with IGCC were reported in an article titled "Utilities Split on Readiness of IGCC" in the October 2006 issue of *Power*. Among the concerns were the following (Javetski 2006):

- Failure of any of the four currently operating IGCC plants to reach 80 percent availability when the standard for PC units is 90 percent
- Lack of standardization among the current IGCC candidate technologies
- The "vexing" nature of the technology's costs
- Performance penalties associated with the use of low-rank fuels such as Powder River Basin coal
- Difficulties in securing power sales agreements and project financing for an IGCC plant that has higher costs than competing PC plants

The investor-owned utility that requires recovery of its investment through regulatory agency-approved rates must be prudent in exposure to risk. During SPR's presentation of the integrated resource plan before the Public Utilities Commission of Nevada, PC units using a supercritical cycle were selected and approved to fulfill future energy generation needs. IGCC will be considered for future projects as the technology matures and the level of risk diminishes.

6.0 AIR QUALITY IMPACT ANALYSIS

An air quality impact analysis (AQIA) was completed for the EEC to determine impacts from the proposed plant. Because of the length of the AQIA, it is included as a stand-alone document in Appendix A9 of this application. The AQIA includes both Class I and Class II evaluations and a visibility analysis. The results of the AQIA indicate that the proposed EEC will not adversely impact the ability to achieve AAQSs and visibility requirements.

7.0 SUMMARY

SPR is proposing to build a new power generation facility, the EEC, in White Pine County near Ely, Nevada. The Sierra Pacific Power Company and Nevada Power Company will own and jointly operate the EEC. The EEC is a vital part of SPR's integrated resource plan for supplying electric power to meet Nevada's growing demand for electricity. The proposed EEC will consist of a two-unit PC plant. The EEC will use a supercritical cycle and be designed to fire western sub-bituminous coal. Each unit will be rated at 750 MW nominal generating capacity. Ancillary plant equipment will include fuel and waste preparation and handling equipment; fuel and waste loading and unloading, transfer, and storage facilities; a distillate oil-fired auxiliary boiler; fire protection equipment; and auxiliary power generators.

The proposed EEC will include sources that have the potential to emit regulated air pollutants at levels exceeding the thresholds; therefore, these sources are classified as major stationary sources. As such, these sources require a PSD evaluation and are subject to various NSPS and NESHAP requirements. This application lists all the applicable requirements. Control equipment for all the processes was selected based on the findings of a BACT analysis (see Appendix B).

The selected BACTs for the main PC boilers are SCR with LNBs and over fire air for NO_X control, wet FGD for SO_2 control, activated carbon injection for mercury control, a fabric filter system for PM and lead control, wet FGD for HF and H_2SO_4 control, and combustion controls for CO and VOC control.

The BACTs for the 220 mmBtu/hr distillate oil-fired auxiliary boiler were determined to be LNBs for NO_X control, limiting fuel sulfur content to less than or equal to 0.0015 percent for SO_2 and H_2SO_4 control, and combustion controls for CO and VOC control. PM will be controlled by using distillate oil, a low-ash fuel. No significant emissions of lead or fluoride will result from the auxiliary boiler.

The BACTs for the 3,100-hp plant diesel engine auxiliary generator, 525-hp diesel fire water pump, 455-hp diesel SO_2 absorber emergency quench pump, 675-hp switchyard diesel engine auxiliary generator, and 80-hp propane communication auxiliary generator for NO_X, SO_2, H_2SO_4, CO, VOC, and PM control include limiting fuel sulfur content to less than or equal to 0.0015 percent and purchasing equipment that complies with regulations for manufacturers set forth in 40 CFR 60 Subpart IIII. Significant emissions of lead and fluoride will not result from the diesel engine generators or pumps.

The BACTs for the material handling and storage facilities include use of partial enclosures, dust collectors, telescoping chutes and lowering wells, as may be appropriate, to control PM and PM_{10} emissions.

The BACT for controlling PM emissions from the cooling towers was identified as drift eliminators with control of draft to 0.0005 percent of the circulating rate.

The Air Quality Control Region in Nevada has been defined historically by hydrographic basins for evaluating the attainment status for criteria air pollutants and protection of PSD increments. An air quality impact analysis and an evaluation of the Class 2 increment consumption in Hydrographic Basin 179 were performed for the EEC (see Appendix A9). Air dispersion modeling results demonstrate EEC complies with all the federal and Nevada AAQSs, PSD Class II increments, Class I increments, and other AQRVs.

8.0 REFERENCES

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APPENDIX A

NDEP PERMIT APPLICATION FOR CLASS I OPERATING PERMIT TO CONSTRUCT

A1 – Emission Unit Application Forms
A2 – Insignificant Activity Information Form
A3 – Facility-Wide Applicable Requirements
A4 – Streamlining and Shield Allowance (Not applicable)
A5 – Facility-Wide Potential to Emit Tables
A6 – Detailed Emissions Calculations
A7 – Emissions Cap (Not applicable)
A8 – Narrative Description, Process Flow Diagram, Plot Plan, Map, and Dust Control Plan
A9 – Air Quality Impact Analysis and Dispersion Modeling Files
A10 – Application Certification

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

ATTACHMENT A

REFERENCE MATERIALS

ATTACHMENT B

PERMIT TEMPLATE